

## NATURAL GAS

### *Production*

Indonesia has almost 190 trillion cubic feet (TCF) of natural gas reserves (proven and probable), the thirteenth largest in the world. In 2004, the country produced 3.03 trillion cubic feet (TCF) of gas, ranking eighth in world gas production. Gas reserves are equivalent to almost four times Indonesia's oil reserves and can supply the country for 62 years at current production rates. According to the GOI, over 71 percent of natural gas reserves are located offshore, with the largest reserves found off Natuna Island (28.8 percent), East Kalimantan (25.2 percent), South Sumatra (13 percent) and Irian Jaya (12.8 percent). However, not all of these reserves are commercially viable, due to both the quality of the gas and the distance to market.

In 2004, Indonesia supplied 19 percent of the world's LNG, down from 26 percent in 2003. LNG accounts for 43 percent of the country's total natural gas production and is exported mainly to Japan, South Korea and Taiwan. Pipeline gas exports to Singapore began in 2001, reaching 129 BCF last year. A new Sumatra-Singapore pipeline was inaugurated in late 2003. Revenues from gas exports are substantial -- \$8.1 billion in 2004, about 11 percent of Indonesia's total export revenues. Domestically, gas demand comes primarily from fertilizer and petrochemical plants (34 percent) and the power industry (25 percent). Most of Indonesia's gas comes from East Kalimantan (47 TCF in reserves) and Sumatra (42 TCF in reserves), but there are large reserves in Papua (24 TCF) and other areas in the archipelago (75 TCF). Six major companies dominate the

industry and account for 90 percent of all production.

**Gross Natural Gas Production by Major Producers (MMSCF)**

Company	2002	2003	2004	% Change
Total	835.031	877.523	909.932	3.69
ExxonMobil	557.873	601.673	507.096	-15.72
Vico	438.982	392.625	329.511	-16.07
BP	272.113	245.296	182.209	-25.72
Pertamina	258.012	263.194	383.870	45.85
Unocal	149.317	144.844	124.199	-14.25
ConocoPhillips	233.411	297.922	319.317	7.18
Others	297.134	332.166	273.998	-17.51
<b>Total</b>	<b>3,041.873</b>	<b>3,155.243</b>	<b>3,030.132</b>	<b>-3.97</b>

Source: MIGAS

Roughly 55 percent of Indonesia's natural gas was marketed as LNG or liquefied petroleum gas (LPG) for export, 5.6 percent for electricity, 6.4 percent for fertilizer and 3.4 percent for city gas. Less than six percent was flared.

Indonesia still maintains its lead as the world's top LNG exporter; however its share in the global LNG markets is declining. Questions over supply reliability, low investment in the energy sector and uncertainty over domestic gas supply policy have contributed to Indonesia's declining market share. As a result, Oman, Qatar, Russia, and Australia are displacing Indonesian LNG on world markets. Domestically, the reduction of fuel subsidies in October 2005 eased fuel price distortions and made natural gas increasingly competitive as a fuel alternative. The GOI has indicated that gas will play a significant role in meeting the country's growing electric power demands.

As new LNG producers, Indonesia's a regional gas transmission network is developing, creating new gas markets and sources of revenue. Pipeline exports of natural gas have offset in part the greater competition in LNG markets. Pipeline

gas exports increased over 131 percent between 2003 and 2004, reaching 129 BCF, accounting for 8 percent of gas export volume. Indonesia began exporting 325 mmcf/d to Singapore via a subsea pipeline from West Natuna under a 22-year contract in 2001. Deliveries of natural gas to Malaysia's Duyong gas platform began in August 2002, under a 20-year contract for 250 million cubic feet per day (mmcf/d). Gas sale revenues will likely total \$14.2 billion over the life of both contracts. In August 2003, the South Sumatra-Singapore gas pipeline was completed; it will eventually supply 350 mmcf/d over a 20-year contract.

### *Lower Subsidies, New Laws Stimulate Domestic Demand*

The phasing out of domestic fuel subsidies should also stimulate gas demand. The government eliminated the subsidy for industry fuels in 2005 and plans to completely phase out premium fuel and gasoil subsidies by the end of 2006. In October 2005, state gas company PGN raised industrial gas prices to \$4.5 per mmbtu from \$3.9 per mmbtu. In January 2006 PGN raised prices again to \$5 per mmbtu. Even at this price, however, gas is still equivalent to only about 21 cents per liter of diesel oil compared to industrial diesel oil price of 56 cents/liter.

The Oil and Gas Law of 2001 introduced other changes that encourage domestic gas use. The new law permits direct "free market" negotiations of gas contracts between buyer and seller. Previously, production sharing contractors (PSCs) had to sell their gas to the state-owned petroleum company, Pertamina, which in turn sold the gas to the final buyer. Several PSCs report that the GOI's new direct negotiation

mechanism is working well and that the upstream authority BP Migas has generally stayed out of the negotiations, except in cases where either the buyer or seller requested its participation.

These provisions have raised domestic demand estimates and led to a number of new gas sales agreements. In December 2004, PSCs and gas buyers signed 18 gas and LPG agreements worth \$4.02 billion. During 2005, gas producers signed at least 17 agreements under the direct marketing mechanism that will supply gas to power, industry and petrochemical buyers. PGN projects conservatively that between now and 2015, Indonesia's domestic gas demand will increase by as much as 60 percent to 3.7 bcf/d.

### *Growing Power Needs Will Drive Gas Demand*

Power generation needs in Java and Bali will also drive growing domestic gas demand. Over the last several years, peak power demand grew by an average of six percent annually, while power capacity did not increase. Peak loads on the Java-Bali grid (which accounts for 80 percent of Indonesia's power demand) reached a record high of 14,821 MW in April 2005. As a result, the actual reserve margin has declined from 16 percent in 2001 to a razor-thin 6 percent in 2004 in (Note: desired reserve margins are normally between 25 and 30 percent).

PLN estimates that Indonesia needs over 23,000 MW in new capacity between 2005 and 2015 to prevent a long-term power crisis and restore its power reserve margin. Much of that new capacity will be fueled by gas and coal. PLN plans to raise natural gas use by the power sector from 17 percent in 2004 to 40 percent by

2015. By volume, this means an increase from 483 mmcf/d to 1.7 billion cubic feet per day (bcfd) in 2015. Presently PLN plans for three new power plants to come online in 2006, including the 740 MW gas turbine combined cycle (GTCC) Cilegon.

Increasing gas consumption in the energy mix makes strong economic sense, particularly with current crude oil price levels. About 2,700 MW of PLN's GTCC plants in Java are running on fuel oil because of declining gas supply and transmission problems in East Java. Petroleum-based fuels are expensive – about 6.2 cents per kilowatt hour (kWh), or 2.5 times more costly than gas. PLN spends about \$1.6 billion annually on oil-based fuels and estimates it can save up to \$1 billion per year by switching to gas. This however, requires a reliable gas infrastructure and security of gas supply. The switch, when coupled with the power utility's plans to raise electricity tariffs, is an important element in restoring the financial health of Indonesia's power industry. At the same time, it also has significant implications for Indonesia's export revenues derived from natural gas.

### ***Impediments to Domestic Gas Growth***

In its Energy Blueprint, the Ministry of Energy and Mineral Resources plans to increase gas's proportion in the national energy mix to 30.6% by 2025 from the current 26.5%. However despite changes spurring gas demand, impediments limit domestic gas growth. The primary obstacles include a limited transmission and distribution system, financing limitations, and continued regulatory uncertainty. To address the inadequate state of gas transmission and distribution

networks, state gas utility PGN plans four new transmission projects to meet rising power sector demands for gas, as follows:

Projects	Length (km)	Capacity (mmscfd)	Completion
Grissik – W.Java	661	400	2007
Duri – Medan	521	250	2007
E.. Kalimantan - Central Java	1,219	1,100	2007/2010
E.Java-W.Java	680	350	2008/2010

Source: PGN

In addition to these projects, the GOI is proposing to build an LNG receiving terminal in West Java, to process and distribute gas from existing LNG plants (Bontang), as well as future plants in Papua (Tangguh) and South Sulawesi (Donggi). PGN is extending its distribution network and plans to ship compressed natural gas (CNG) over short to medium distances to remote areas. In addition, PGN is also investigating the feasibility of developing an integrated mini-LNG transportation system. The project will involve a mini-LNG receiving terminal located in Makassar, South Sulawesi, which will ship LNG from the Bontang LNG plant.

Many producers require explicit financial guarantees to sell gas domestically. The government's reluctance to provide such guarantees poses another obstacle to domestic gas growth, according to industry observers. In the power industry, a number of PSCs have requested that PLN provide standby letters of credit (SBLC) before investing in long-term gas supply agreements. According to industry analysts, PLN's credit availability with government-linked banks is limited. PLN has asked Bank Indonesia to exclude SBLCs from the legal lending limit to get around this obstacle. Some power analysts suggest that if PLN would permit higher returns on investment, companies

would be willing to assume more of this risk themselves.

Another constraint to gas development is the absence of a competitive gas pricing system. Under the historic system, prices for gas supply contracts are negotiated on a field-by-field basis between Pertamina and individual producers after the discovery of the gas field. Prices are fixed for a designated supply for the duration of the contract. Hence, the producer's price for gas is different for each PSC. Consumer prices are set on a cost-plus basis.

Currently, the negotiated gas price for power generation is far below the global average, in the range of \$2.45 to \$3 per MMBTU, compared to current global natural gas prices, which currently averages at around \$7 per mmbtu in early 2006. The World Bank and the Asian Development Bank (ADB) have urged Indonesia to adopt a pricing regime that creates greater incentives for companies to find and produce gas. A competitive domestic gas price would allow Indonesia to realize the full value and potential of its gas reserves. Without pricing changes, the domestic gas market provides few incentives for the exploration and development of gas fields that are too small to support LNG but more than adequate for domestic gas customers. A second major constraint is the absence of a predictable basis for forecasting the future value of gas, such as an indexed price formula. A final constraint has been the subsidy provided for alternative fuels.

### *Regulations Require Clarification*

The current regulatory environment sends mixed signals to investors which inhibits

the exploration and development of potential gas reserves. Despite domestic market obligation (DMO) provisions in the 2001 Oil and Gas law promoting gas use and the issuance of downstream Regulation 36, industry players still do not see a clear set of "rule of the game." Industry players say that they want clarification of the exact DMO quantity and whether the government will honor existing PSC contracts. In addition, doubts about contract sanctity, contract extensions, security, and taxation hurt the gas investment climate.

The end result of this uncertainty, and the consequent lack of exploration, is stark: According to the American Chamber of Commerce, gas blocks signed before 1971 still account for nearly 60 percent of Indonesia's commercial reserves. Blocks signed after 1990 account for only 14 percent of commercial reserves.

### *Expanding Future Production*

Indonesia is blessed with abundant reserves, although there is a geographical mismatch between location of gas reserves and energy needs. The Ministry of Energy and Mineral Resources estimates total gas demand between 2008-2018 will reach 22,200 BSCF, while supply is estimated at 13,231 BSCF. In the long-term, Java's additional gas supply will rely on the development of gas fields outside the island and completion of pipeline projects.

In addition to geographical constraints, other barriers to developing Indonesia's gas resources include the availability of financing, long project lead-time, and the lack of incentives to explore and exploit gas reserves.

Private sector participants identified the following key areas to increase development in the gas sector:

- Increase incentives to find and produce natural gas;
- Harmonize conflicting laws and eliminate the lengthy bureaucratic process for project approval;
- Clarify the gas DMO obligation;
- Promote private investment and ownership, through price stability, an equitable cost recovery mechanism;
- Address gas reliability concerns for those firms that invest in major gas facilities; and
- Government guarantees for gas payment by state owned enterprises.

### *A Trans-ASEAN Gas Pipeline?*

ASEAN's Energy ministers signed a memorandum of understanding on July 5, 2002 to push ahead with a \$7 billion natural gas pipeline project in a bid to alleviate concerns over supply shortages and to improve economic development. Minister of Energy and Mineral Resources Purnomo Yusgiantoro said the project's masterplan has been completed, and a council will soon be established to oversee the completion of the gas grid. Purnomo said more than 1,000 kilometers of the grid have already been constructed. ASEAN has identified the need for 4,500 kilometers of pipeline to complete the project, which might reach 6,000 kilometers, if the necessary new Indonesian domestic pipelines are included.

Purnomo said Indonesia will be a major player in the trans-ASEAN gas pipeline

project because of its enormous gas reserves. ASEAN members have previously said that a regional natural gas pipeline, as well as an electricity grid, is the most efficient way for ASEAN countries to prevent a future energy crisis. Indonesia has already developed several pipelines - from West Natuna to Singapore, West Natuna to Malaysia, and from South Sumatra to Singapore. It is also studying a possible pipeline from West Natuna to Thailand.

ASEAN members will develop regulations and frameworks for the cross-border supply, transportation and distribution of natural gas throughout the region. This will be supervised by a future ASEAN Gas Consultative Council. The key reason behind the gas grid is the need to reduce oil consumption and to provide backup energy sources for ASEAN members. ASEAN members hope to complete the gas grid by 2020.

### *Integrated Transmission System*

The South Sumatra pipeline is part of state gas company PGN's plan for an integrated gas transmission pipeline system, known as the Integrated Gas Transportation System (IGTS). The IGTS will eventually link the islands of Sumatra, Java, and Kalimantan via a 4,200-kilometer integrated gas pipeline. Reputed to be Southeast Asia's longest, the pipeline is being funded by the World Bank, ADB, other institutions, as well as PGN's own internal funding. PGN's network will flow 2.2 BCFD of natural gas after its scheduled completion in 2010.

**Project One - Grissik-Duri Pipeline**  
Phase One became operational in 1998. The 544-kilometer Grissik/Duri gas transmission pipeline transports 310



mmscfd of natural gas from the Grissik gas plant in ConocoPhillips Indonesia's Corridor PSC in South Sumatra. The project will supply Caltex's Duri Steam Flood Project in Central Sumatra for 15 years. ConocoPhillips is the producer, Caltex is the buyer, and PGN is the pipeline network owner.

The Grissik/Duri pipeline project is the first part of an 850-kilometer gas transmission pipeline to link South Sumatra to Singapore. Phase Two, which covers a 530-kilometer leg from Grissik to Singapore by way of Batam Island was completed in August 2003. Both the Grissik/Duri pipeline and the Grissik/Singapore pipeline have been included in the TransgasIndo pipeline consortium, jointly owned and operated by PGN and a joint venture among ConocoPhillips, Petronas, Talisman, and Singapore Petroleum.

**Project Two: South Sumatra–West Java Pipeline:** This 1,100-kilometer pipeline project will provide gas from ConocoPhillips and Pertamina fields in Sumatra to West Java power plants and industrial users. The pipeline will be funded by a combination of JBIC loans and proceeds from a PGN bond and IPO offerings. All parties hope to complete the project and have the first gas flowing in mid 2007.

Phase I of the project involves construction of a 450 kilometers pipeline from Pagardewa, South Sumatra to Cilegon and Serpong, West Java. Phase I will provide 250 mmcfd of gas from Pertamina's Pagardewa gas field and ConocoPhillips' Grissik field to the Muara Tawar, Tanjung Priok and Muara Karang gas-fired power plants in Jakarta. Currently, Phase I completion date is scheduled for March 2007.

Phase II will connect Grissik to Pagardewa via a 270 km pipeline, a parallel line from Pagardewa to Labuhan Maringgai and a 190 km pipeline from Labuhan Maringgai to Muara Bekasi, and Rawamaju in West Java. Phase II will provide 400 mmcfd (ramping up to 600 mmcfd). PGN completed the procurement tender for the project in 2005 and aims for project completion in December 2007. This pipeline will supply natural gas from Pertamina's gas fields in Prabumulih to West Java industrial users. Pertamina and PGN have already agreed to provide 250 mmcfd to West Java once the pipeline becomes operational.

**Project Three: East Kalimantan–Central Java:** The most ambitious of the five projects, the 1,200-kilometer East Kalimantan-Java pipeline would transport up to 1.1 bcf/d of gas through a combined offshore and onshore pipeline stretching from Kuala Badak, East Kalimantan to Semarang, Central Java. PGN would partially fund the project from a bond and IPO offering. At an estimated cost of \$1.2 billion, PGN will need substantial outside financing. PGN completed the feasibility study of the project and announced the tender in December 2005. Presently, PGN plans for project construction to begin in 2007 with first gas flowing in 2010.

**Project Four: East/West Java Pipeline:** This proposed project will involve construction of a 730 kilometers pipeline stretching from Gresik (East Java) to Cirebon and Muara Bekasi (West Java) along with a 300-kilometer East and Central Java distribution link. The pipeline will have the capacity to transport about 700 mmcfd of natural gas and cost an estimated \$540 million. Currently PGN plans for project construction to start in 2008 with completion in 2010.

**Project Five: Duri – Dumai – Medan**

**Pipeline:** An extension of the Grissik-Duri project, the 521-kilometer pipeline will transport gas from Duri, Riau to Medan, North Sumatra. The project will be the northern extension of an integrated Sumatra transmission network and supply gas to Asahan Power. PGN, Kondur Petroleum and Asahan Power signed MOU in October 2004 for the sale of 80-140 mmcf/d gas through the pipeline. PGN plans to finance the estimated \$574 million project via internal and external finance lending. Currently, PGN plans for project completion in 2007.